MEMORANDUM

DATE: July 28, 2011

SUBJECT: Natural Gas Production NSPS – Technology Reviews

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TO: Bruce Moore, EPA/OAQPS/SPPD/CCG

The purpose of this memorandum is to present the results of a review to identify any developments in practices, processes, and control technologies for pollutant emission sources for the Oil and Natural Gas Production New Source Performance Standards (NSPS). This analysis is part of EPA's review efforts in accordance with section 111(b)(1)(B) of the Clean Air Act.

Section 1 provides background information on section 111(b)(1)(B), the source categories, and the requirements of the NSPS that address emissions from these categories. Section 2 discusses the exploration of developments in practices, processes, and control technologies that have occurred since the original development of these NSPS, and Section 3 provides the conclusions of this investigation.

1.0 BACKGROUND

1.1 Section 111(b)(1)(B)

Section 111 of the Clean Air Act requires EPA to establish standards of performance for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. These standards are often referred to as new source performance standards, or NSPS standards. Section 111 also contains provisions requiring EPA to revisit these standards. Specifically, paragraph 112(b)(1)(B) section states:

> (B) … The Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for promulgation of such standards. Notwithstanding the requirements of the previous sentence, the Administrator need not review any such standard if the Administrator determines that such review is not appropriate in light of readily available information on the efficacy of such standard…

1.2 Description of Source Categories and NSPS Standards

There are two NSPS that currently impact the oil and natural gas production sector. The Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants (40 CFR 60, subpart KKK) addresses volatile organic compound (VOC) emissions from leaking equipment at onshore natural gas processing plants. The Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions (40 CFR 60, subpart LLL) addresses sulfur dioxide (SO_2) emissions from natural gas processing plants.

The natural gas processing segment of the oil and natural gas sector includes the processing of raw natural gas to produce "pipeline quality" dry natural gas. Natural gas is primarily made up of methane, but often contains water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. While some of the processing can be accomplished in the production segment, most of the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (NGL) or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility. Natural gas processing plants are the only operations covered by the existing NSPS.

Equipment Leaks from Onshore Natural Gas Processing Plants

Equipment leaks are emissions from valves, pump seals, flanges, compressor seals, pressure relief valves, open-ended lines, and other process and operation components. The amount of pollutant emissions from equipment leaks is dependent on the type and number of equipment components and the leak rate of those components. Components such as pumps, valves, pressure relief valves, flanges, agitators, and compressors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines, and sampling connections may leak for reasons other than faulty seals. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions.

Subpart KKK requires the natural gas processing facility to monitor components using a leak detection and repair (LDAR) program as described in 40 CFR part 61, subpart VV. For most components, this requires monthly inspection of the components using a volatile organic compound (VOC) detection instrument. If a leak greater than 10,000 parts per million is detected, then the facility is required to repair that leak in 15 days.

SO_2 Emissions from Onshore Natural Gas Processing

Raw natural gas often contains water vapor, H_2S, CO_2, helium, nitrogen and other compounds. When the natural gas contains H_2S and CO_2, it is referred to as "sour gas" and removal of the components is required to produce "pipeline quality" dry natural gas. If the gas is sour, then H_2S and CO_2 need to be removed in an acid gas removal process called "sweetening". The sweetening process separates the acid gases (H_2S and CO_2) from the field gas. The acid gas is then further processed for elemental sulfur recovery. The most common sulfur recovery unit is the Claus process, which uses a series of catalytic stages to recover approximately 97 percent of the sulfur. Subpart LLL provides specific standards for additional SO_2 emission reduction efficiency, on the basis of sulfur feed rate and the sulfur content of the natural gas. The regulation applies to facilities that have a design capacity equal to or greater than 2 long tons per day of H_2S. The minimum SO_2 percent reduction efficiency ranges from 74 percent (acid gas streams with a less than 10 percent H_2S content and a sulfur feed rate greater than or equal to 2 long tons per day) to 99.8 percent (acid gas streams with a H_2S content of greater than or equal to 50 percent and a sulfur feed rate greater than 300 long tons per day).

2.0 PRACTICES, PROCESSES, AND CONTROL TECHNOLOGIES

For the purpose of this exercise, EPA considered a "development" in the natural gas processing segment to be:

- Any add-on control technology or other equipment (e.g., floating roofs for storage tanks) that was not identified and considered during NSPS development,
- Any improvements in add-on control technology or other equipment (that was identified and considered during NSPS development) that could result in significant additional emission reduction,
- Any work practice or operational procedure that was not identified and considered during NSPS development, and
- Any process change or pollution prevention alternative that could be broadly applied that was not identified and considered during NSPS development.

Table 1 summarizes the practices, processes, and control technologies considered during the development of the NSPS standards for these categories. This is followed by descriptions of the searches for developments since that time. The specific information sources that were consulted in this effort included EPA's RACT/BACT/LAER clearinghouse (section 2.1), current EPA LDAR programs (Section 2.2), and direct correspondence with the industry (section 2.3).

Table 1. Summary of Practices, Processes, and Control Technologies Identified and Considered for the Natural Gas Processing NSPS Development

Source Category/ Emission Source	Practices, Processes, and Control Technologies
Natural Gas Processing	
Equipment Leaks	Leak detection and repair programs, specific equipment modifications
Sulfur Recovery Unit	2-Stage Claus, 3-Stage Claus, Cold Bed Adsorption, Tail Gas Treatment

2.1 RACT/BACT/LAER Clearinghouse

Under EPA's New Source Review (NSR) program, if a company is planning to build a new plant or modify an existing plant such that air pollution emissions will increase by a large amount, then the company must obtain an NSR permit. The NSR permit is a construction permit which requires the company to minimize air pollution emissions by changing the process to prevent air pollution and/or installing air pollution control equipment. In obtaining an NSR permit, a source will be required to install one of the following:

- Reasonably Available Control Technology (RACT), is required on existing sources in areas that are not meeting national ambient air quality standards (i.e., non-attainment areas). RACT is a control technology that is reasonably available, and both technologically and economically feasible.
- Best Available Control Technology (BACT), is required on major new or modified sources in attainment areas and is an emissions limitation that represents the maximum degree of control that a source can achieve. BACT can be add-on control equipment or process modification.
- Lowest Achievable Emission Rate (LAER), is required on major new or modified sources in non-attainment areas and represents the most stringent emission limitation contained in any State implementation plant (SIP) or the most stringent emission limitation achieved in practice by a source.

BACT and LAER (and sometimes RACT) are determined on a case-by-case basis, usually by State or local permitting agencies. EPA established the RACT/BACT/LAER Clearinghouse, or RBLC, to provide a central data base of air pollution technology information (including past BACT and LAER decisions contained in NSR permits) to promote the sharing of information among permitting agencies and to aid in future case-by-case determinations.

These practices, processes, and control technologies are all examples of the types of emission reduction techniques that were considered in the development of NSPS for equipment leaks and SO_2 emissions at natural gas processing plants. The RBLC search identified two entries with SO_2 emission reductions of 99.9 percent, but neither provided information on the H_2S content of the feed stream.

Table 2. Summary of the RBLC Processes, Practices, and Control Technologies for SO_2 Control and Equipment Leaks at Natural Gas Processing Facilities

Control Method Identified in RBLC	*Considered under NSPS? (Y/N)*	*Comments*
SO_2 Control		
Thermal/Catalytic Oxidizer	Y	
2-Stage Claus	Y	
3-Stage Claus	Y	
Recycle Selectox	Y	
Tail Gas Cleanup	Y	
Equipment Leaks		
Leak Detection and Repair	Y	The current NSPS requires a 40 CFR part 60, subpart VV LDAR program. A 40 CFR part 60, subpart VVa LDAR program and alternative work practices were also reviewed.
Low Emission Design Equipment	N	This technology has not yet been proven to be effective for reducing emissions.

2.2 Current EPA LDAR Programs

The current NSPS for equipment leaks for natural gas processing facilities requires compliance with specific provisions of 40 CFR part 60, subpart VV. This subpart VV-level LDAR program requires monthly monitoring of valves and a leak definition of 10,000 ppm. Since the promulgation of the 40 CFR part 60, subpart KKK requirements, EPA has developed a more stringent LDAR program (40 CFR part 60, subpart VVa) that lowers the leak definition to 500 ppm and includes the annual monitoring of connectors. There have also been advancements in optical gas imaging and ultrasound LDAR monitoring. These instruments measure the magnitude of the leak, but are unable to measure the concentration of the leak. The general control device and work practice requirements in 40 CFR part 60, subpart A allow for the use of these instruments as an alternative to the Method 21 monitoring.

2.3 Natural Gas STAR

New practices, processes, and control technologies were reviewed from the Natural Gas STAR program. The Natural Gas STAR Program is a flexible, voluntary partnership that encourages oil and natural gas companies to adopt cost-effective technologies and practices that improve operational efficiency and reduce pollutant emissions. The program provides the oil and gas industry with information on new techniques and developments to reduce pollutant emissions from the various processes.

Equipment Leaks

- Ultrasound Leak Detection[1] - Ultrasound leak detectors are used to reveal high frequency sounds associated with gas leakage. The ultrasound detector indicates whether the valve is tightly shut and the magnitude of leakage.
- Directed Inspection and Maintenance[2] - A directed inspection and maintenance program begins with a baseline survey to identify and quantify leaks. Repairs are then made to only the leaking components that are cost-effective to fix, based on criteria such as repair cost, expected life of the repair, and payback period. Subsequent surveys are designed based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair.
- Compressor Rod Packing Systems[3] – Increased frequency of reciprocating engine compressor rod packing replacement can reduce methane, VOC, and HAP emissions from compressors.
- Replacement of Wet Seals with Dry Seals[4] – Replacement of wet seals with dry seals reduces operating costs and methane, VOC, and HAP emissions from centrifugal compressors.

The ultrasonic leak detection provides the magnitude of the leak, but does not quantify the leak. This option is allowed as an alternative work practice under 40 CFR part 60, subpart A. The directed inspection and maintenance program was not considered because it is based on the criteria of cost of repair versus emission reductions. The compressor rod packing and dry seal replacement options reduce leaking emissions from compressors. These options were considered as effective options for reducing VOC emissions. It was determined that compressor emissions should be addressed separately in the NSPS, because the current LDAR regulations do not address the replacement of rod packing for reciprocal engines or dry seals for centrifugal compressors directly. Therefore, these options will be included in the compressor portion of the new NSPS.

Sulfur Recovery Units

The Natural Gas STAR program did not provide any new or emerging technologies for sulfur recovery.

[1] EPA (2004). Partner Reported Opportunities: Use Ultrasound to Identify Leaks. Natural Gas STAR.
[2] EPA (2006). Lessons Learned: Directed Inspection and Maintenance at Gas Processing Plants and Booster Stations. Natural Gas STAR.
[3] EPA (2006). Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems. Natural Gas STAR.
[4] EPA (2006). Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors. Natural Gas STAR.

3.0 CONCLUSIONS

In order to identify developments in practices, processes, or control technologies that could be used to further reduce emissions from Natural Gas Processing, the following sources of information were searched: EPA's RACT/BACT/LAER clearinghouse, and Natural Gas STAR.

For sulfur recovery, the RBLC results identified two facilities that achieved 99.9 percent control efficiency of sulfur using a Claus sulfur recovery unit with a tail gas treating unit. Based on this information, the original NSPS data was reevaluated and it was discovered that a 99.9 percent SO2 reduction technology was cost effective for facilities with a sulfur feed rate of 5 long tons per day and a H_2S content equal to or greater than 50 percent. Therefore, this option was not considered a development in practices, processes or control technologies as it was considered in the development of the existing NSPS.

For equipment leaks, the RBLC and Natural Gas STAR programs did not provide any additional practices or technologies for reducing HAP from equipment leaks. The only new developments for equipment leaks were found in EPA's current LDAR programs. In addition to the current requirements in 40 CFR part 60, subpart VV, EPA has promulgated more stringent LDAR programs that include: 40 CFR part 60, subpart VVa and alternative work practices under 40 CFR part 60, subpart A. The subpart VVa-level program has a leak definition of 500 ppm and includes the annual monitoring of connectors. The general control device and work practice requirements in 40 CFR part 60, subpart A allow for the monthly monitoring of components using an optical gas imaging and ultrasound equipment with an annual Method 21–based LDAR check. Each of these options was evaluated for the new NSPS. The compressor packing and seal replacement are effective options for reducing VOC and methane emissions from reciprocating and centrifugal compressors. Therefore, reciprocating and centrifugal compressors were evaluated separately for the new NSPS for all of the oil and gas segments.

ATTACHMENT 1

INFORMATION FROM THE RACT/BACT/LAER CLEARINGHOUSE

RBLC Information for Equipment Leaks

RBLCID	FACILITY_NAME	SIC_CODE	NAICS_CODE	PROCESS_NAME	PROCCESS_TYPE	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	PERCENT_EFFICIENCY
CA-1145	BREITBURN ENERGY - NEWLOVE LEASE, ORCUTT HILL FIELD	1311	212299	OIL AND GAS: FUGITIVE COMPONENTS	13.39	EQUIP: LOW-EMISSION DESIGN VALVES, CONNECTIONS AND SEALS (SEE BELOW), MFR: VARIOUS, TYPE: VALVES, FLANGES, PUMP SEALS, COMPRESSOR SEALS, ETC, MODEL: VARIOUS, FUNC EQUIP: PIPING COMPONENTS IN OILFIELD OPERATIONS, FUEL_TYPE: , SCHEDULE: CONTINUOUS, H/D: 24, D/W: 7, W/Y: 365, NOTES: VALVES: BELLOWS, DIAPHRAGM SEAL, SPRING-LOADED PACKING, EXPANDABLE PACKING, GRAPHITE PACKING, PTE-COATED PACKING, PRECISION MACHINED STEM, SEALANT INJECTION AND LDAR: 100 PPMV THC. FLANGES/CONNECTORS/OTHER: WELDED, NEW GASKET RATED TO 150% OF PROCESS PRESSURE AT PROCESS TEMPERATURE. LDAR: 100 PPMV THC COMPRESSOR SEALS (ROTARY DRIVE): VENTED TO VAPOR RECOVERY OR CLOSED VENT, DUAL/TANDEM MECHANICAL SEALS, LEAKLESS DESIGN (E.G. MAGNETIC DRIVE). LDAR: 100 PPMV THC COMPRESSOR SEALS (RECIPROCATING DRIVE): VENTED TO VAPOR RECOVERY, ELASTOMER BELLOWS, O-RING SEALS, DRY RUNNING SECONDARY CONTAINMENT SEALS. LDAR: 100 PPMV THC PUMP SEALS: VENTED TO VAPOR RECOVERY OR CLOSED VENT, DUAL/TANDEM MECHANICAL SEALS. LDAR: 500 PPMV THC PRDS: VENTED TO VAPOR RECOVERY OR CLOSED VENT, SOFT-SEAT DESIGN. LDAR: 100 PPMV THC SOURCE TEST RESULTS:	VOC	A	LOW EMISSIONS DESIGN AND LOWER LDAR THRESHOLD (SEE BELOW)	100	PPMV	0
IL-0073	EXXONMOBIL OIL CORPORATION	2911	324110	FUGITIVES	50.007		VOC	N		3.76	T/YR	0
LA-0228	BATON ROUGE JUNCTION FACILITY	4613	486910	FUG002 FUGITIVE EMISSIONS	42.004		VOC	P	CONDUCT A LEAK DETECTION AND REPAIR PROGRAM AS SPECIFIED BY 40 CFR 63 SUBPART R	7.44	T/YR	0
TX-0364	SALT CREEK GAS PLANT	1321	211112	FUGITIVES, NGLFUG	50.007		VOC	N	NONE INDICATED	9.08	LB/H	0
TX-0364	SALT CREEK GAS PLANT	1321	211112	FUGITIVES, CO2FUG	50.007		VOC	N	NONE INDICATED	9.33	LB/H	0
TX-0440	CORPUS CHRISTI LNG	4922	221210	FUGITIVES (4)	50.007		VOC	N		1.96	LB/H	0
TX-0454	EL PASO NATURAL GAS CORNUDAS COMPRESSOR STATION	4922	486210	FUGITIVES (4)	64.002		VOC	N		0.13	LB/H	0
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	351	333311	PLANT FUGITIVES (4)	64.002		VOC	N		0.07	LB/H	0
TX-0465	SALT CREEK GAS PLANT	1321	221210	FUGITIVES (4)	64.002		VOC	N		9.08	LB/H	0
TX-0465	SALT CREEK GAS PLANT	1321	221210	FUGITIVES	64.002		VOC	N		9.33	LB/H	0
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	2911	324110	FUGITIVES (4)	50.007	TOTAL UNCONTROLLED FUGITIVE EMISSIONS ARE LESS THAN 10 TPY, SO NO MONITORING IS REQUIRED. THE COMPANY WILL IMPLEMENT DAILY WALKTHROUGHS TO INSPECT THE PIPING. THERE ARE ALSO H2S MONITORS ON SITE TO CAPTURE ANY H2S LEAKS.	VOC	N		0.88	LB/H	0

RBLC Information for Sulfur Recovery Units

RBLCID	FACILITY_NAME	SIC_CODE	NAICS_CODE	PROCESS_NAME	PROCESS_TYPE	THROUGHPUT	THROUGHPUT_UNIT	PROCESS_NOTES	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	PERCENT_EFFICIENCY
AL-0171	MOBIL OIL EXPLORATION & PRODUCING SOUTHEAST, INC.	1311	211111	NATURAL GAS SWEETNING, DEHYRATION	50.002	160	MMSCF/D	SULFUR RECOVERY FOLLOWED BY THERMAL OXIDIZATION. THROUGHPUT ALSO INCLUDES 280 TON SULFUR/DAY	Sulfur Dioxide (SO2)	P	SCR AND THERMAL OXIDIZER	511	LB/H	99.9
AL-0174	MOBIL OIL EXPLORATION & PRODUCING SOUTHEAST, INC.	1311	211111	NATURAL GAS SWEETENING AND DEHYDRATION	50.002				Sulfur Dioxide (SO2)	P	SWEET FUEL GAS	0.25	GRAIN/100 SCF	0
AL-0175	MOBIL OIL EXPLORATION & PRODUCING SOUTHEAST, INC.	1311	211111	SULFUR RECOVERY UNIT	50.002				Sulfur Dioxide (SO2)	A	SCR AND THERMAL OXIDIZER	105.5	LB/H	90
CA-0413	TEXACO REFINING AND MARKETING	1311		CLAUS SULFUR RECOVERY UNIT	50.006	90	LONG TPD		Sulfur Dioxide (SO2)	A	AMINE-BASED TAIL-GAS TREATING UNIT	10	PPM H2S INCIN FEED	99.9
CA-0523	MOBIL OIL COMPANY	1311		TEOR OPERATION (WITH SULFUR REMOVAL)	50.006	150000	SCFD		Sulfur Dioxide (SO2)	A	SULFA CHECK SULFUR SCRUBBING SYSTEM FOR H2S	29.1	LB/DAY	95
LA-0011.B	LOUISIANA OPERATIONS	138	221210	INCINERATOR, TAIL GAS, SULFUR RECOVERY	62.019	10	MMBTU/H		Sulfur Dioxide (SO2)	P	GOOD COMBUSTION PRACTICES	524	LB/H	0
LA-0059	CITGO PETROLEUM CORP.	1311	324110	TREATING UNIT, TAILGAS	50.006	1.3	MMDSCF/H		Hydrogen Sulfide	P	SULFTEN PROCESS	10	PPMV	0
LA-0059	CITGO PETROLEUM CORP.	1311	324110	TREATING UNIT, TAILGAS	50.006	1.3	MMDSCF/H		Sulfur, Total Reduced (TRS)	P	SULFTEN PROCESS	300	PPMV	0
ND-0010	WESTERN GAS RESOURCES,INC.	1321	211112	AMINE TREATING AND FLARE	50.002	6	MM CUBIC FEET/DAY		Sulfur Dioxide (SO2)	N		116	LB/HR	0
NM-0018	LIQUID ENERGY CORP.	1321	211112	AMINE UNIT	50.002	20	MMSCFD		Sulfur Dioxide (SO2)	A	SCR, COLD BED ADSORPTION	123.3	T/YR	98
NM-0020	LIQUID ENERGY CORP.	1321	211112	AMINE UNIT	50.002	40	MMSCFD		Sulfur Dioxide (SO2)	A	SRU 4-STATE CLAUS PROCESS	246.5	T/YR	98
TX-0501	TEXSTAR GAS PROCESS FACILITY	132	221210	TAIL GAS INCINERATOR STACK	19.9				Sulfur Dioxide (SO2)	N		350	LB/H	0
TX-0501	TEXSTAR GAS PROCESS FACILITY	132	221210	TAIL GAS INCINERATOR STACK	19.9				Hydrogen Sulfide	N		10	LB/H	0
WY-0024	LOUISIANA LAND & EXPLORATION CO.- LOST CABIN GAS PT	1311		INCINERATOR, TAIL GAS (PHASE II)	50.006	17	SCFM	SCOT TAIL GAS INCINERATOR FOLLOWING A 3 STAGE CLAUS PLANT.	Hydrogen Sulfide	P	PRIMARY CONCERN AT FACILITY MINIMIZING SO2 EMISSIONS.	0.8	LB/H	0
WY-0024	LOUISIANA LAND & EXPLORATION CO.- LOST CABIN GAS PT	1311		INCINERATOR, TAIL GAS (PHASE II)	50.006	17	SCFM	SCOT TAIL GAS INCINERATOR FOLLOWING A 3 STAGE CLAUS PLANT.	Sulfur Dioxide (SO2)	B	3 STAGE CLAUS PLANT FOLLOWED BY SCOT TAIL GAS SYSTEM	115	LB/H	99.8
WY-0041	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	1311	211111	INCINERATOR, TAIL GAS, 2 EACH	50.006	19250	SCFH	ONE INCINERATOR PER PHASE.	Sulfur Dioxide (SO2)	A	3 - STAGE CLAUS PLANT AND A SCOT TAIL GAS UNIT	79.8	LB/H	99.8
WY-0041	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	1311	211111	INCINERATOR, TAIL GAS, 2 EACH	50.006	19250	SCFH	ONE INCINERATOR PER PHASE.	Hydrogen Sulfide	N		0.6	LB/H	0
WY-0042	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	1311	211111	INCINERATOR, TAIL GAS	50.006	17000	SCFM	SHELL CLAUS OFFGAS TREATING (SCOT) TAIL GAS INCINERATOR FOLLOWING A 3-STAGE CLAUS PLANT.	Hydrogen Sulfide	A	3-STAGE CLAUS PLANT TO BE FOLLOWED BY SCOT TAIL GAS SYSTEM	0.8	LB/H	96
WY-0042	LOUISIANA LAND AND EXPLORATION COMPANY-LOST CABIN	1311	211111	INCINERATOR, TAIL GAS	50.006	17000	SCFM	SHELL CLAUS OFFGAS TREATING (SCOT) TAIL GAS INCINERATOR FOLLOWING A 3-STAGE CLAUS PLANT.	Sulfur Dioxide (SO2)	A	3 STAGE CLAUS PLANT AND SCOT TAIL GAS SYSTEM	115	LB/H	99.8
WY-0056	LA LAND & EXPLORATION CO. - LOST CABIN GAS PLANT	1311		CLAUS/ SCOT SULFUR RECOVERY UNITS, TRAIN 3	50.002			TAIL GAS INCINERATOR BURNS TAIL GAS FROM SHELL CLAUS OFF GAS TREATING (SCOT) UNIT. SULFUR RECOVERY OF TRAIN III CLAUS/ SCOT UNITS TO BE NO LESS THAN 99.8%. CEMS TO BE USED.	Hydrogen Sulfide	A	TAIL GAS INCINCERATOR TREATS H2S AND OTHER SULFUR COMPOUNDS EMITTED BY THE CLAUS/SCOT PROCESS AND, AS A RESULT, GENERATES CO, NOX AND SO2. ALSO SEE POLLUTANT NOTES.	2.2	LB/H	0
WY-0056	LA LAND & EXPLORATION CO. - LOST CABIN GAS PLANT	1311		CLAUS/ SCOT SULFUR RECOVERY UNITS, TRAIN 3	50.002			TAIL GAS INCINERATOR BURNS TAIL GAS FROM SHELL CLAUS OFF GAS TREATING (SCOT) UNIT. SULFUR RECOVERY OF TRAIN III CLAUS/ SCOT UNITS TO BE NO LESS THAN 99.8%. CEMS TO BE USED.	Sulfur Dioxide (SO2)	N	SEE POLLUTANT NOTES	312	LB/H	0